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NEW ENERGY TECHNOLOGIES IN THE NATURAL GAS SECTOR: A POLICY FRAMEWORK FOR JAPAN

Executive Summary Report

Natural gas is expected to play an expanding role in meeting rising Asian energy demand. Several major natural gas pipeline projects have been proposed, and a series of large-scale liquefied natural gas (LNG) projects have been initiated. The use of natural gas as an energy source in Asia in 1999 was 10 percent of total primary energy use, which was substantially lower than the world average of 23 percent, suggesting tremendous room for growth.

In recent years, technical innovations have driven down the costs of LNG processing and shipping, allowing more LNG projects to achieve commercial viability. The result has been a proliferation of LNG sales in both Asian and Atlantic Basin markets. Besides the decline in costs for LNG and the general growth in LNG trade, the end of the Cold War has also created new natural gas pipeline opportunities in Northeast Asia.

Natural gas is mainly used in Asia for electricity generation and petrochemical feedstock. Petroleum fuels such as gasoline and light oil have dominated as the primary transportation fuels because of the convenience of handling, storage, and transportation for such fuel that can be kept at ordinary temperatures. If natural gas can be imported after converting it into ordinary-temperature liquid fuels, the use of gas in the transportation sector could substantially increase. Since 70 percent of the increase in international oil use is expected to come from the transportation sector over the next decade, the ability to utilize plentiful natural gas supplies in manufacturing transportation fuels would greatly contribute to enhanced energy security and environmental protection.

Traditional uses for LNG and pipeline gas—industrial feedstock, power generation fuel, and residential heating and cooking fuels—remain the most practical options for Asia given the advantages of existing infrastructure and other considerations such as cost and safety. However, an expected surplus in Asian gas supplies is spurring an interest in other supplemental technologies for employing natural gas for other uses as well. This study investigates the prospects for increased LNG and natural gas pipeline shipments to Japan and the policy framework that is needed to promote augmented utilization of natural gas there. Discussion includes legal, regulatory, and infrastructure changes that must be made to facilitate increased market penetration of natural gas in Japan, including new supplies from the Sakhalin Islands. The investigation will also cover innovative technologies that might broaden the sectors in which natural gas can replace other fuels.

Japanese Demand Trends

Japan's Institute of Energy Economics (IEEJ) projects that LNG demand for Asia will rise by about 4 to 5 percent per annum to 105 to 112 million (MM) tons/year by 2010. Industry estimates are higher at 108 to 138 MM tons/year (see working paper by Shook/Jaffe). LNG demand in Japan is projected to increase 2 percent per year to 64 MM tons/year, up from 51.30 MM tons/year in 1999.

Japan's natural gas demand in the power generation sector may rise more than expected if the country cannot mobilize public support for the construction of 13 new nuclear energy plants. If the 13 additional nuclear facilities are not built, Japan faces an eventual shortfall of as much as 28 gigawatts (GWe), which will require turning to other energy sources to meet that deficit. If this unbuilt capacity were replaced 100 percent by natural gas, Japan would have to import an additional 186.648 million cubic meters a day (mcm/d). A 30 percent oil/70 percent natural gas replacement scenario would require 350,000 barrels a day (b/d) of imported crude oil and 130.653 mcm/d of natural gas to fuel power generation substituted for scrapped nuclear plants.

Gas Conversion Technologies

Japan and other governments have been exploring the use of natural gas as a raw material to produce liquid fuels. If liquid fuels derived from natural gas can become competitive, they would offer a promising option that could help curb the heavy dependency that Asian countries have on Middle East oil.

There could be a ready Asian market for liquid fuels manufactured from natural gas. Regional refinery output of middle distillates may not be large enough to meet the rising demand for such products. This could create a ready constituency for middle distillates produced from natural gas. The increase in demand for middle distillates such as diesel fuel is expected to be 6.26 million barrels a day (b/d) by 2010 versus an expected increase in fuel oil of 2.41 million b/d over the same period.

There are several technologies that could be useful in substituting natural gas-based liquid fuels for oil-derived fuels. They include gas to liquids (GTL), methanol, DME, LPG, and gas hydrates.

Natural gas can be used as the raw material for manufacturing GTL fuel, producing a final petroleum product (middle distillates, gasoline, or jet fuel) that has extremely clean properties, basically free of sulfur and nitrogen. In recent years, costs of gas-to-liquids conversion have been lowered to the point where commercial plant operations now seem feasible.

A number of firms are planning commercial-sized GTL projects, including Shell, ExxonMobil, Sasol, Sasol/Chevron, and small U.S. independent Syntroleum. The *breakpoint* for profitability for GTL investments is generally considered to be in the $15–20 per barrel (BBL) oil price range, though Shell has claimed it could run a GTL plant on a crude price as low as $14/BBL average. BP says it believes a minimum profitability threshold of $20/BBL average is more realistic (see working paper by Troner).

It should be noted that all GTL projects are also very sensitive to both the base cost of gas and the tax regime for capital costs. Many prospective host countries for GTL projects—such as Qatar—have been willing to ask a moderate price on gas feedstock for either LNG or GTL projects. Increasingly, in order to encourage GTL as an alternative to LNG exports, many natural gas producers—and their state oil companies—are willing to give substantial tax breaks to get GTL projects up and running.

Dimethyl ether (DME) is a fuel produced through oxygenate processes using a natural gas feedstock, whereby gas is first converted into methanol and then the methanol is converted into DME. DME and a similarly produced liquefied natural gas form, dimethoxymethane (DMM), are stable fluid products that can be transported in smaller volumes on liquefied petroleum gas (LPG) tankers. However, DME/DMM production involves a substantial loss of energy in its two-part conversion of gas to methanol and methanol to DME/DMM, with up to 20 percent of gas loss in processing. By comparison, GTL processes and even LNG transport are far more efficient, reducing interest in DME businesses (see working paper by Troner).

Other natural gas-based fuels such as methanol and LPG also face barriers. Methanol conversion from natural gas has yet to reach commercial viability. The long-term prospects of liquefied petroleum gas, which is an indispensable fuel for some isolated areas of Japan, is also being called into question. LPG prices are subject to large fluctuations given the strong influence of Middle East suppliers on LPG supply and price formation. The future of LPG exports into the Asia-Pacific region is likely to be precarious because certain Middle East producers such as Saudi Arabia are planning to use LPG at home as a raw material for petrochemical development, curbing volumes that can be dedicated to Asia (see PEC working paper).

Gas hydrates are the result of the physical entrapment of gas in an ice-like structure, with the gas volumes reduced by 150 times, compared to more than 1,600 times for LNG. Scientists are working to produce a transportation system that could move this gas while still in its ice form. Giant gas hydrate deposits are said to exist offshore around the world and could represent a future avenue for unconventional gas reserves.

Natural Gas Supplies from the Sakhalin Islands: LNG, Pipeline, or Both?

Regardless of any long-term potential of new natural gas technologies, the primary focus of enhanced natural gas utilization in Japan in the coming years is likely to be either LNG or pipeline gas. Each offers certain advantages.

Substantial gas reserves of Russia's Sakhalin Islands (847 trillion cubic feet of proven, probable, and possible reserves) offer Japan the new option to import natural gas by pipeline. The Sakhalin region is about 1,000 kilometers from Hokkaido in northern Japan and 2,200 kilometers from Tokyo. Rule of thumb analyses appear to suggest that given the distances involved, the costs for transporting Sakhalin natural gas to Japan by pipeline or as LNG are likely to be relatively similar (see working paper by Brito/Hartley).

LNG supplies offer Japan certain advantages, including more supply flexibility and less risk of disruption. A supply overhang is expected to be a typical feature of LNG markets in the coming years. Japan is unlikely to have to compete with U.S. buyers for limited LNG supplies. Rather, buyers could have a wide variety of alternative exporters to choose from. Only in the case of prolonged depressed prices might a widespread cancellation of projects limit new supply (see working paper by Shook/Jaffe).

U.S. demand, at 28 to 32 trillion cubic feet (Tcf) by 2010, is likely to exceed substantially domestic sources of natural gas of about 20 to 22 Tcf. Canada's shipments to the U.S. are expected to grow over the decade to 1.6 to 2 Tcf (4.5 to 5 Bcf/d), up from 3.5 Bcf/d currently, while Alaska pipelines could provide as much as 1.5 Tcf (4 Bcf/d) and the Canadian Northwest possibly an additional 0.75 Tcf (2 Bcf/d). Thus, North American continental supply could be as high as 24.85 Tcf to 26.25 Tcf.

In a low demand growth/high supply scenario where coal shaves close to 2 Tcf from demand growth and pipeline projects from Canada and Alaska proceed as planned, U.S natural gas demand could almost be met without resorting to LNG supply. However, even in this most pessimistic scenario, it remains to be seen whether LNG would be shunned by U.S. buyers as a marginal supply since several short-haul LNG projects might have competitive costs and economics that beat out certain higher-cost domestically drilled gas and/or Canadian supply.

In the more robust U.S. natural gas-demand path scenarios, even if North American continental supplies hit the upper ranges of 25 to 26 Tcf, the U.S. market requirement for LNG imports would probably still be no more than around 120 to 140 million tons a year (6–7 Tcf), leaving plenty of potential surplus gas from the Middle East and elsewhere looking for a home in Europe or Asia-Pacific (see working paper by Shook/Jaffe).

PIRA Energy Group of New York projects in a new study on Atlantic Basin LNG markets that expanding LNG supplies to the Atlantic Basin could reach 90 MM tons/year in 2005, of which almost 80 MM tons/year is fairly committed under contract and 5 MM tons/year of capacity (about 6 percent) remains unsold. This compares with 60 MM tons/year in 2000 from Algeria, Libya,

Trinidad, Nigeria, Abu Dhabi, Qatar, and Oman, of which 44 MM tons/year was committed under contract and 15 MM tons/year of export capacity unsold. By 2010, PIRA projects supply will expand to 132 MM tons/year with 20 MM tons/year still to be sold, or roughly 17 percent. PIRA estimates that 32 MM tons/year is still searching for buyers past 2015 or about 25 percent of potential supplies to the Atlantic Basin.

Interestingly, the possibility of a surplus of LNG in Asia as well as in the Atlantic Basin could leave Middle East producers to serve in a swing role, delivering to East or West as demand trends require. CMS Energy, for example, has purchased short-term cargoes from Abu Dhabi, Oman, and Qatar for delivery to the U.S. market. Also, at the end of 2000, Enron signed a short-term contract with Oman LNG for six cargoes of four million tons each for 2001, most of which is expected to come to the Lake Charles, Louisiana, terminal. Some Pacific supplies could also serve to balance regional demand swings as several LNG projects are targeting both Asian buyers and the U.S. West Coast. Shell, for example, is expected to market its contracted volumes from Australia's North West Shelf to the U.S. West Coast (see working paper by Shook/Jaffe).

The greater the interaction of these swing suppliers with both markets, the more likely prices will converge over time. This could be good news for Asian buyers who paid roughly between $4.50 to $5.00 per million Btu in July 2001 for LNG supplies from the Middle East, Malaysia, Indonesia, and Australia compared to a U.S. Gulf coast natural gas price of $3.06 per million Btu in July.

A global LNG market could use the New York Mercantile Exchange (NYMEX) as its primary pricing point, with other trading centers emerging at Zeebrugge in Belgium, Tokyo, and other locations, all indexed off U.S. prices. This would operate in much the same way as oil markets, with West Texas Intermediate, Brent Blend, and Dubai serving as benchmarks. A linked price relationship with U.S. spot natural gas prices on the NYMEX would afford even small Japanese buyers a greater opportunity to hedge transactions through futures and derivatives markets, potentially promoting a wider deployment of natural gas use as deregulation progresses (for a more detailed discussion of the formal model presenting this case, see working paper by Brito/Hartley).

This possibility of radical change in the LNG market favors exploiting the Sakhalin gas deposits in the form of LNG to optimize flexibility. But pipeline supply also has certain advantages including the security and cost advantages of dedicated supply. An import pipeline could help unify the Japanese market, enhancing market competition. A domestic gas grid will also provide wider access to potential users and hence a more diversified customer base, potentially expanding the use of gas in Japan and promoting competition with other fuels (see working paper by Soligo). Pipeline options will not bar Japan from taking advantage of trends in the LNG markets since Sakhalin pipeline gas will account for less than 2 percent of Japan's energy use by 2020.

Sakhalin gas could also be used in Hokkaido to generate electricity, which could then be transported south by wire to key demand centers. To allow the existing transmission system to carry additional power from the north, the capacity of the AC electricity lines in Hokkaido and northern Honshu would need to be upgraded as well as the existing undersea DC line link between the two islands. An alternative would be to build a high-voltage direct current (HVDC) line from northern Hokkaido to the vicinity of the pumped storage facilities and the Shin-Shinano link between the Tokyo and Chubu utility areas (see working paper by Brito/Hartley).

An added advantage to an HVDC scheme to carry electricity from the north is that a parallel HVDC north–south link from Hokkaido to Tokyo would improve stability and controllability of the existing Japanese AC system. The line could also be constructed in a fashion that promotes transfer capability between Japan's 50Hz regions and 60Hz regions, bringing substantial cost savings and enhancing competition in Japan's electricity sector. Besides cost issues, reduced air pollution near population centers may be another substantial benefit of generating electricity at gas fields located in a relatively unpopulated region and transporting the electricity to the major population centers via HVDC. However,

APPENDIX

NEW LNG TRAINS

PROJECT	SIZE (MM TONS/YEAR)	STARTUP
Abu Dhabi	2.0–3.8	2010 or beyond
Alaska LNG	7.7	2010
Angola	4.3	2005–06
Australia–Gorgon	8.0	2005–06
Australia–Greater Sunrise	4.8	2005–06
Australian–North West Shelf	4.2	2004–05
Bolivia	7.7	2006
Brunei	3.0–4.0	2008
Egypt (BG)	3.0	2004
Egypt (BP)	7.7	2005
Egypt (Shell)	4.0	2004
Egypt (Union Fenosa)	3.0	2005
Equatorial Guinea	4.0	2008
Indonesia (Tangguh)	8.0	2005–06
Iran (BP)	10.0	2008–09
Iran (Shell)	7.0–8.0	Under study
Iran (TotalFinaElf)	7.0-8.0	Under study
Nigeria–Bonny 3	3.0	2005
Nigeria–Bonny 4&5	8.5	2007–08
Nigeria II	4.7	2007–08
Nigeria III	5.0	2008
Norway–Snohvit	4.0	2006
Oman	3.3	2004–05
Peru–Camisea	4.3	2005–06
Qatar (Qatargas)	3.1-4.0	2004
Qatar (RasGas)	5	2004
Sakhalin II	9.6	2006
Timor Sea–Bayu Undan	5.8	2005–06
Trinidad 2&3	6.0	2004–05
Trinidad 4	5.5	2006–07
Venezuela Jose	2.0	2005
Venezuela–Paria	4.3	2006
Yemen	6.2	2004–05
TOTAL	**175.7-181.4**	

(Source: Industry, EIG's World Gas Intelligence, Asia Pacific Consulting)

electricity shipments would not allow as diverse a use of the Sakhalin natural gas, which if shipped directly to mainland Japan, could be used for fueling industry and households as well as electricity generation.

Policy Recommendations and Conclusions

Japan's energy security and environmental goals can be enhanced through greater utilization of natural gas in its energy mix. At present, LNG and pipeline gas remain the most practical means to utilize more natural gas inside Japan given the advantages of existing infrastructure and other considerations such as cost and safety. A combination of LNG and pipeline gas imports would enhance natural gas trade in smaller volume increments, increasing the number of sectors that might use natural gas. It would also increase competition and likely lower costs without jeopardizing supply stability and security. Government support of research in emerging natural gas technologies could also help augment deployment of gas to new sectors inside Japan.

In order to facilitate the augmentation of gas markets, regulatory changes to Japan's existing Gas Law are needed. The preparation of new laws, regulations, and procedures should not be allowed to impede the efficient introduction of new fuels and the expansion of natural gas pipelines.

The introduction of new fuels such as GTL and DME and the construction of international pipelines were not considered in the formation of existing laws and regulations. An effort to adapt these products and the building of pipelines to existing laws will likely result in a good deal of confusion and many delays. Thus, adjustments to these laws, regulations, and procedures should be made quickly to enhance the introduction of new fuels and facilities.

Administration of laws and regulations should be made in a nondiscriminatory manner where all market players, including new entrants into a liberalized market, compete on equal terms. New entrants should be allowed access to gas infrastructure but at a price that includes a fair return to investors for access to infrastructure. Market transparency and agreed network codes can then maintain the level playing field between players.

All prices, of both natural gas as well as its competitive fuel alternatives, need to be market based and transparent such that inter-fuel and gas-to-gas competition will establish the most competitive delivered price to the end-user.

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